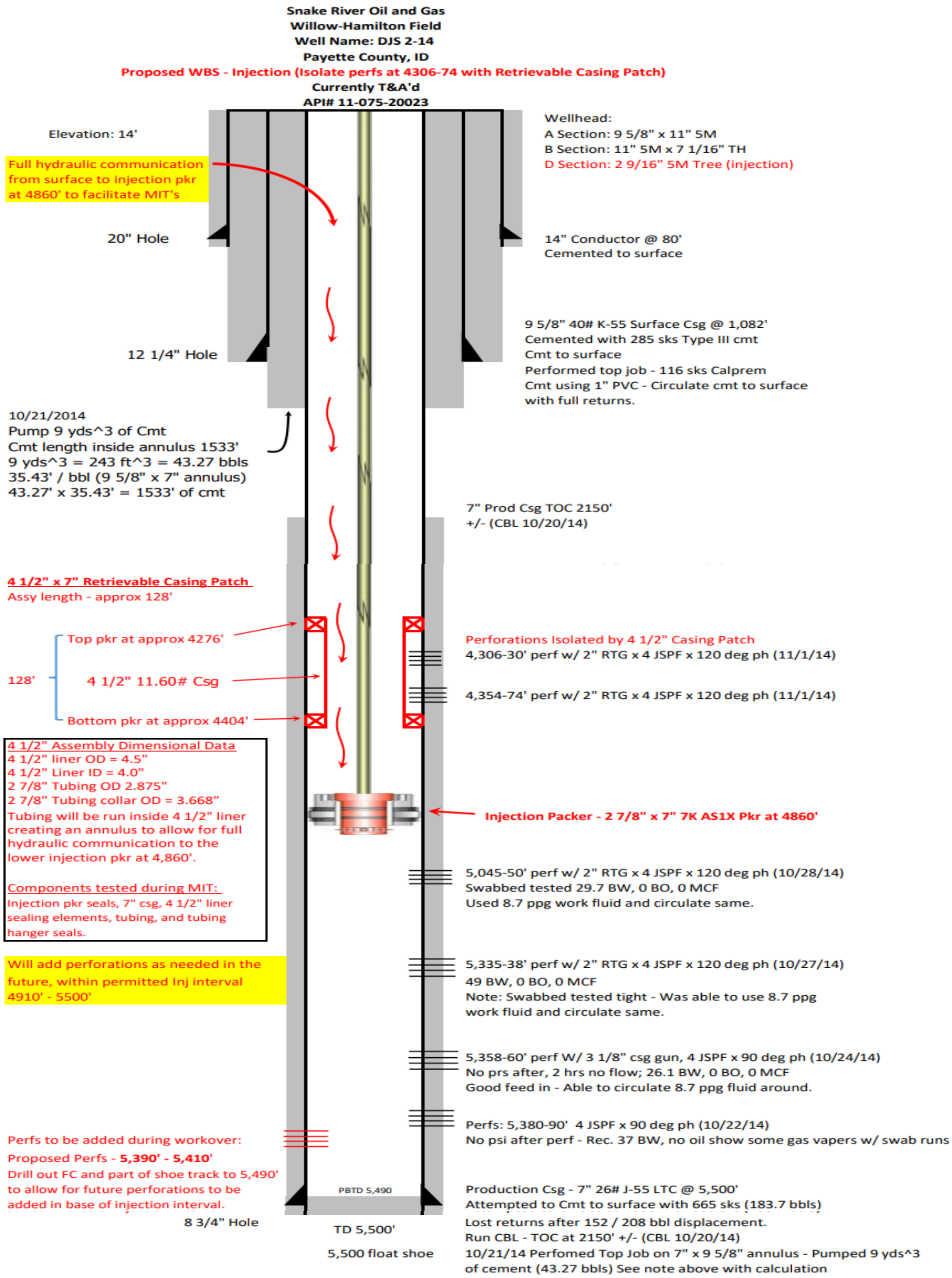
Revision to page 45 - Attachment L – Construction Procedures

<u>Planned Well Construction Procedure for Injection:</u>

1. Move in workover rig
2. Pressure test 7” casing above bridge plug at 4,294’.
3. Drill out plugs, cement retainers, and part of shoe track to 5,490’ (Injection interval 4,910’ – 5,500’).
4. Add perforations at 5,390’ – 5,410’.
5. Run injection tubing and packer with 4 ½” x 7” casing liner to isolate perforations at 4,306’- 4,330’; 4,354’ – 4,374’. See proposed wellbore diagram.
6. Set injection packer at approx. 4,860’.
7. Pressure test 2 7/8” x 7” annulus (communicated from surface to injection packer). See proposed wellbore diagram.
8. Install wellhead assembly.
9. Run step rate test with actual produced water to determine parting pressure and injectivity.
10. Connect gauges and filter pod, flowline, pump, and commission injection system.

Revision to Page 50 - Attachment M - Proposed Injection Wellbore Diagram



Perforating Plan:

Additional injection intervals will perforated, as needed, at a later date in the permitted interval. This will be performed using wireline and perforating guns conveyed through the tubing, so that disturbing the tubing and packers will not be necessary. Adding perforations will likely be needed to communicate with all of the anticipated injection pore space, as variations in vertical permeability will restrict the vertical flow of fluid throughout the permitted injection interval.

The strategy of delaying addition of perforations provides a number of benefits.

1) The present value of the well operation is maximized by pushing the costs of perforating into the future.
2) In addition, as additional intervals are added, knowledge will be gained as to the injectivity of intervals and the associated well log petrophysical characteristics which can be correlated to injection.
3) In the event that something was to be injected downhole that caused damage (decreased injectivity) to the perforated interval sandface, all of the permitted interval will not be exposed to the damaging event and could be added to the completion as needed. Potential damaging materials could include mineral scale, iron rust, or other solids that could potentially enter the system.

Additional Casing liner Info

The proposed method for isolating the perforations that are above the Permitted Injection Interval (4,306' – 4,330'; 4,354' – 4,374') is a standard casing liner section / casing patch with respective casing packers above and below the perforations.

The assembly will consist of two (2) 4 ½"x 7" Casing packers and approx. 128' of standard API 4 ½"11.60# J-55 LTC casing which will be run across the perforations (4,306' – 4,330'; 4,354' – 4,374').

The lower packer will be set at approx. 4,404', with the upper packer set at approx. 4,276', with the 4 ½" casing liner section connecting the two packers.

The perforations (4,306' – 4,330'; 4,354' – 4,374') will be isolated behind the 4 ½" casing and between the two casing packers.

The injection tubing string (2 7/8") will be run from surface, through the 4 ½" casing liner section, with the injection packer below the liner section at the proposed depth of 4,860', this will allow the injection tubing the ability to move freely inside the liner section as in any other completion. This downhole set up will provide the traditional and adequate tubing / casing annulus that will have full continuity from surface to the injection packer allowing for a true MIT operation. MIT's performed with this downhole set up will determine the integrity of multiple sealing areas consistent with standard MITs:

- External tubing integrity
- Tubing hanger and seals
- 7" casing above the 4 ½" liner section and below the liner section.
- Injection packer seals
- 4 ½"x 7" packer seals
- 4 ½" liner section

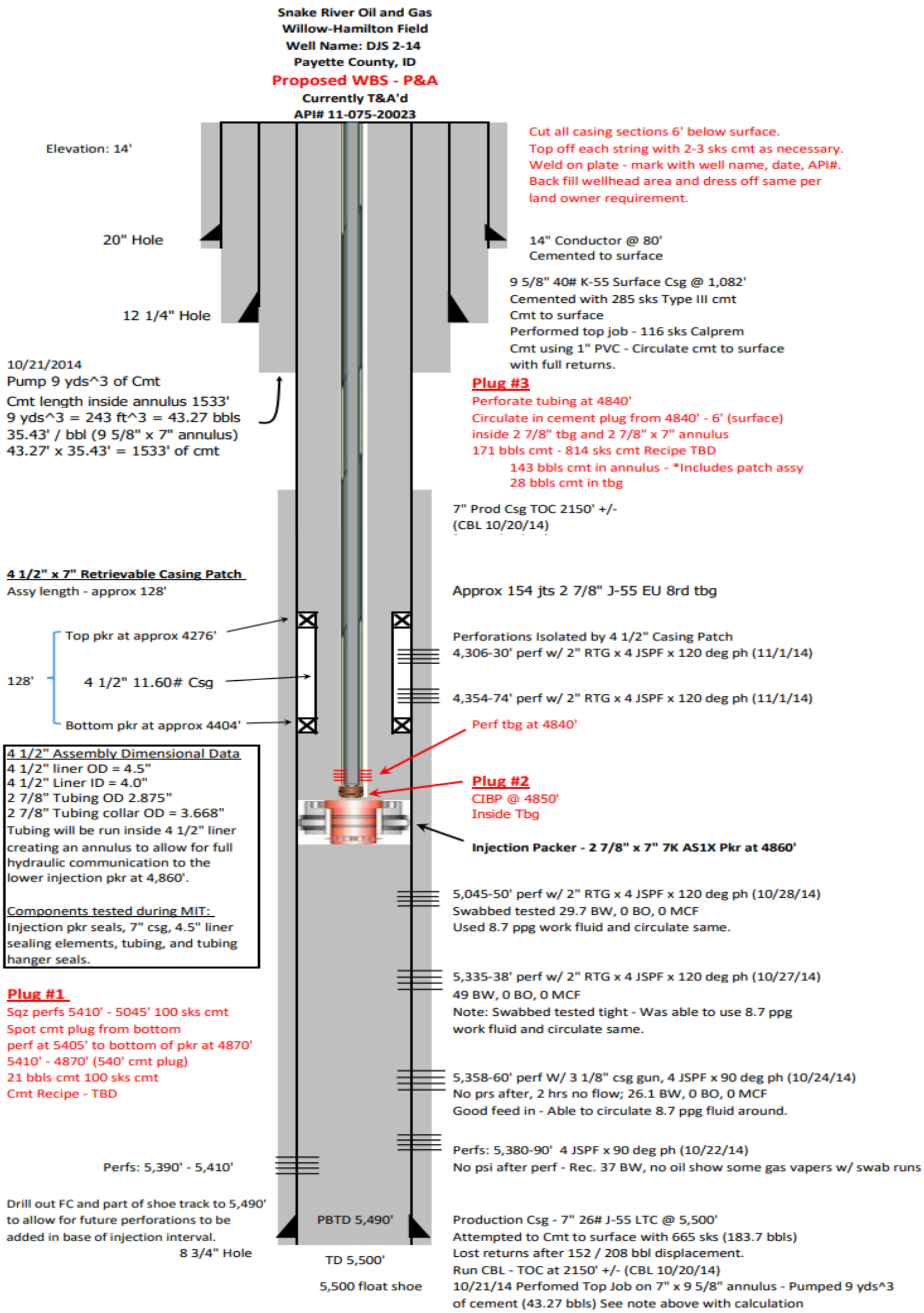
4 ½" Liner Running Procedure

1. PU 2 7/8" x 7" AS1X Injection packer.
2. RIH with BHA and 456' of NEW 2 7/8" 6.5# J-55 EUE 8rd tbg
3. MU 4.5" x 7" 11.60# L-80 x 2 7/8" 6.5# J-55 EU 8rd Casing liner with 2 7/8" tbg hung off in liner clutch assembly.
    a. Casing liner to consist of 128' assy – 2 mechanical / compression set pkrs (Viton High Temp/High Pressure elastomers)
        i. Packer sealing elements will have a pressure rating of 5,000 psi (minimum).
        ii. Packer sealing elements will have a temperature rating of 350 deg F (minimum).
    b. Liner packers spaced out to be set at approx. 4276' & 4404' (30' above and 30' below the perforations to be isolated.
    c. Continue running 2 7/8" tubing as normal – Approx 4276'.
4. Set 4 ½" liner system
    a. PU full stroke of inner mandrel approx. 12' engaging clutch into patch body.
    b. Rotate left ½ turn and slack off to set bottom slips and pack off liner packer element.
    c. Continue to slack off and shear and set top slips of the liner packer.
    d. Continue slacking off and compress top packer element.
    e. Liner packer assembly is now set and independent of the tubing string.
        i. Note: The tubing can now move freely and function separately from the liner section.
    f. NOTE: Will run tube moves to determine optimal slack off weight on liner packer assembly.
5. Displace 2 7/8" x 7" annulus with fluid (biocide, corr inhib, oxy scavenger).
6. Space out and set 7" AS1X injection packer at 4,860' and land tubing hanger in tubing head bowl.
7. Test backside to 1,000 psi for 10 mins (determine actual test pressure for MIT dictated by EPA).
    a. Record MIT on chart – test duration TBD.
    b. Components that will be tested during the MIT
        i. External tubing integrity
        ii. Tubing hanger and seals
        iii. 7" casing above the 4 ½" liner section and below the liner section
        iv. Injection packer seals
        v. 4 ½"x 7" packer seals
        vi. 4 ½" liner section

Revision to Page 51 - Attachment O - Plans for well failures

PLANS FOR WELL FAILURES -- The potential areas of concern for this type well are three points: 1) packer to casing seal, 2) tubing connections or tubing body leak, or 3) tubing hanger seals. For any of these components a leak will be indicated by the existence of pressure on the tubing / casing annulus pressure gauge. These type of leaks will be contained within the wellbore envelope. If pressure is observed on the casing gauge, injection operations will immediately cease. The wellhead will be isolated by closing in all wellhead valves and the pump and flowline valves will be closed. The tubing hanger seals will be inspected using a wellhead service company technician who can pressure test the seals for leaks. After this testing is done, a workover rig will be utilized to repair the leaking seals or to pull the tubing and packer so that they can be inspected for leaks and replaced as necessary. Injection will not be reinstated until the leak is repaired and the annulus is pressure tested to verify integrity of the injection components. Mechanical integrity tests will be run periodically according to permit requirements by applying pressure on the annulus between the production casing and the tubing. This test is designed to detect any leaks / weakness in the production casing, the 4 ½" casing liner isolating the perforations at 4,306' – 4,330'; 4,354' – 4,374', as well as the injection packer. If any leaks are noted, injection operations will not resume until the leak is located and repaired.

Revision to page 54 – Attachment Q-1 Proposed Post-Injection Plug and Abandon Wellbore Diagram



Revision to page 55 – Attachment Q-2 Proposed Plugging and Abandonment Plan

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Snake River Oil and Gas, LLC,
117 East Calhoun St., Magnolia, AR 71753

Permit or EPA ID Number	API Number	Full Well Name
ID2D001-A	11-075-20023	DJS Properties #2-14

State	County
Idaho	Payette

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

NE 1/4 of NW 1/4 of Section 14 Township 8N Range 4W

Latitude 44.038666 (NAD83)

Longitude -116.783310 (NAD83)

95 ft. from (N/S) N Line of quarter section
2315 ft. from (E/W) W Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☑ Class II ☐ Class III ☐ Class V	☑ Notice Prior to Work Date Expected to Commence: Injection Permit Proposal ☐ Report After Work Date Work Ended: N/A	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

1. MIRU electric wireline unit and cement unit.
2. Bleed off any gas accumulation in tubing or on backside. Fill casing with water as necessary.
3. Establish injection rate into perforations with water down tubing.
4. Mix and pump approx 100 sks cement down tubing into perforations, leaving a cement plug from 5,410' - 4,870' **(Plug #1 5,410' - 4,870').**
5. Set CIBP inside tubing at 4,850' and pressure test same **(Plug #2 4,850').**
6. Perforate tubing at 4,840'.
7. Mix 814 sks cement and circulate in cement plug from 4,840' to 6'. Cement to be left inside tubing and the tubing / casing annulus from 4,840' - 6' **(Plug #3 4,840' - 6').**
8. RD electric wireline unit and cement unit. Wait on cement for 24 hrs.
9. Move in backhoe. Nipple down 2 9/16" wellhead. Dig out bell hole 8' below surface. RU welder.
10. Cut windows on 14" conductor and 9 5/8" casing at 6'.
11. Make primary cut on 9 5/8" casing, 7" casing, and 2 7/8" tubing. Remove casing head and tubing head, along with the cut pieces of casing and tubing. Cut 14" conductor at 6' and remove same. Make final cuts flush on all strings.
12. Weld on 14" steel closure plate. Weld API#, date, and location into plate. Backfill bell hole. Restore location. See attached proposed wellbore schematic, illustrating proposed plugged well condition. Note: All depths are based on the measurements from the drilling rig kelly busing, as directed by the Schlumberger Platform Express - Triple Combo Open Hole Log dated 9/18/14.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title (Please type or print)	Signature	Date Signed
Richard Brown, Manager	Richard Brown	1-6-2021

EPA Form 7520-19 (Rev. 4-19)

Revision to page 56 – Q-3 Proposed plugging and abandonment cost estimate

HTI Services, LLC

Thursday, June 25, 2020

To: Snake River Oil and Gas
117 E Calhoun
Magnolia AR 70753

Re: DJS 2-14 Plug

Below is an estimated cost and procedure summary for plugging and abandoning the DJS 2-14 disposal well based on the provided proposed P&A Wellbore Schematic. The estimated cost included is based on past well abandonments done without a rig in the Willow Field that is located in Payette County Idaho.

Procedure Summary:

1. MIRU wireline unit and cement unit.
2. Squeeze perfs and spot cement plug from 5,410' - 4,870' (Plug #1).
3. Set CIBP inside tubing at 4,850' (Plug #2).
4. Perforate tubing at 4,840'.
5. Mix 814 sks cement and spot long balanced plug from 4,840' - 6'. Cement will be inside tubing and inside tubing / casing annulus (Plug #3).
6. RD Cement unit and wireline unit.
7. Move in backhoe and welder. Nipple down 2 9/16" wellhead and dig bell hole 8' below surface.
8. Cut all casing strings down to 6'. Weld on plate to conductor.
9. Backfill bell hole and dress off same.

Estimated Cost Breakdown:

Cement Crews and Cement	$26,250.00
E-Log Services	$32,000.00
Vacuum Trucking Services / Welder	$8,500.00
Disposal Services / Rentals and Location Clean Up.	$2,500.00
Estimated Total Cost	$69,250.00

Please feel free to contact myself directly if you have any questions.

Robert Hatfield
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